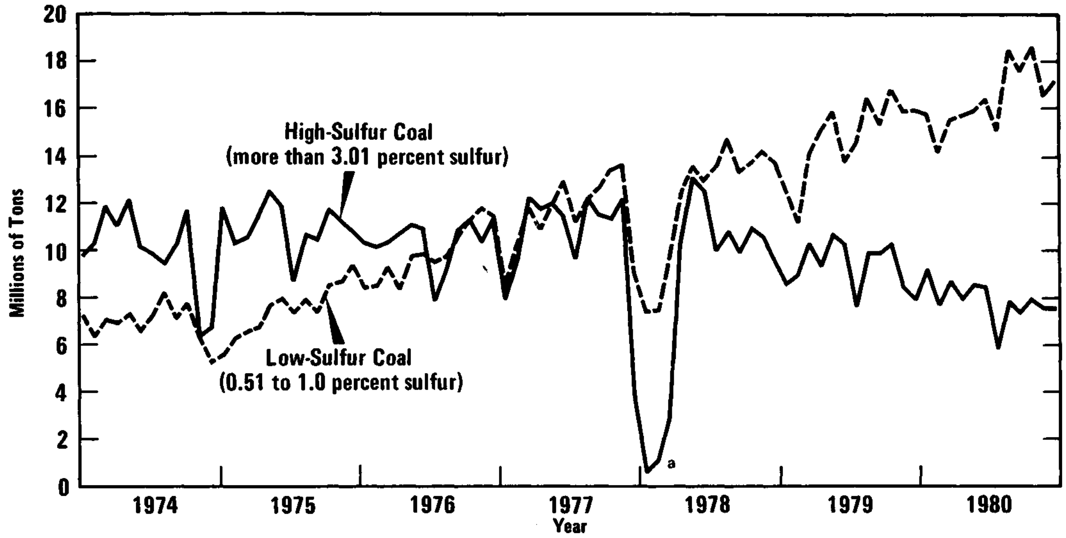
Figure 5.

Monthly Deliveries of Coal to U.S. Electric Utilities, by Sulfur Content: 1974-1980



SOURCE: Adapted by CBO from data provided by Data Resources, Inc.

[a] Drop coincident with mine workers' strike.

promulgated in 1971. 6/ At the same time, the rate of high-sulfur coal deliveries slackened. Though possibly related to one another and reflecting some displacement of high- by low-sulfur coal, these two trends cannot be construed as conclusive evidence of the Clean Air Act's effects. Other factors also have to be taken into account.

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6. By no means should the divergence of high- and low-sulfur coal demand in the late 1970s be taken as any indication of the effects of the revised NSPS of 1978. Because utilities' efforts at compliance with the revised NSPS are still very much on the planning or initial construction stages, the 1978 NSPS are unlikely to yield any measurable effects on fuel markets for another decade or more. Far more reasonable, though still tenuous owing to an insufficiency of data, is a possible correlation between the older NSPS and shifts in the coal market in the late 1970s and early 1980s. Even so, much of the perceived shifts may be attributable to tighter state regulations under the act limiting the emissions of some older power plants not covered by federal emissions standards.

Much of the increase in overall low-sulfur coal demand observed in the 1970s stemmed from the large increase in low-sulfur western coal consumption also observed during this period, an increase not necessarily in response to sulfur dioxide regulations and not necessarily resulting from regional shifts in the coal market. Though consumption of western coal rose by 145 percent between 1974 and 1979, the rise can be ascribed more to increased local consumption than to the attractiveness of western coal's low-sulfur characteristics to distant buyers. During those years, annual coal consumption in the West South Central, Mountain, and Pacific areas alone increased by 73 million tons; the nationwide increase for all coals during those years was 94 million tons. (Figures 6 and 7 outline the specific U.S. regions of coal supply and demand, which are also used in the coal market projections described in Appendix B.) At the same time, however, western coal shipments to midwestern consumers in Ohio, Illinois, and Indiana (the largest users of western coal east of the Mississippi) rose by only 10 million tons. 7/ For the most part, coal-burning utilities in those states continued to rely on local fuel, and of the total increase in national coal consumption between 1974 and 1979, less than 11 percent involved increased shipments of western coal to the three midwestern states. As stated above, mines in the East, notably in Appalachia, also yield significant amounts of low-sulfur coal. Thus, eastern suppliers too may have shared in the increased use of low-sulfur coal.

For the portion of low-sulfur western coal that was shipped east during the 1970s, mining costs may have been as strong an element as emissions regulations in stimulating its demand. As stated above, much low-sulfur coal, by virtue of being located in the West where surface-mining methods predominate, tends to incur relatively low recovery costs. Furthermore, western surface mines are more productive than many midwestern surface mines. In 1979, the average FOB price of surface-mined coal from Montana and Colorado ranged from $9.76 to $13.13 per ton, while that from Illinois, Indiana, and Ohio ranged from $19.21 to $21.13 per ton. 8/ Thus, this factor too may have contributed to the increased use of low-sulfur coal during the late 1970s.

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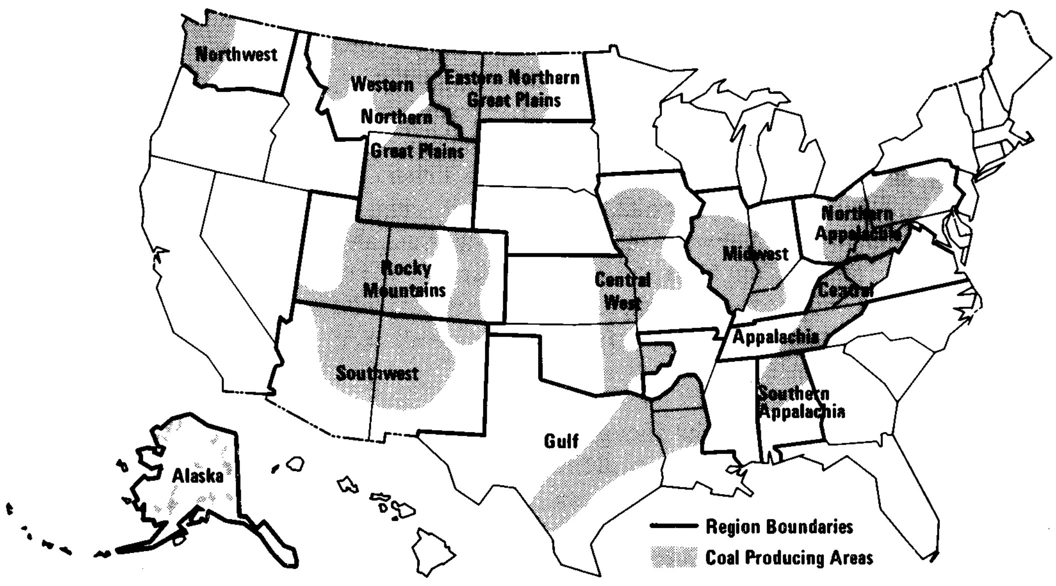
7. See U.S. Department of Energy, Bituminous Coal and Lignite Distribution, Calendar Year 1978 (April 1979); see also, U.S. Department of Energy, Bituminous Coal and Lignite Distribution, Calendar Year 1979 (April 1980).

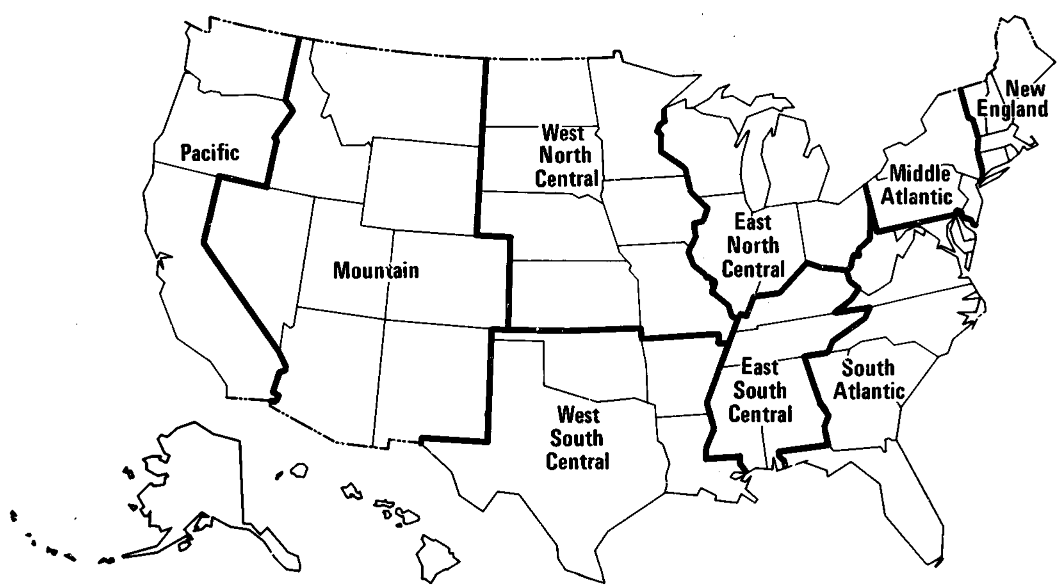
8. See U.S. Department of Energy, Coal Production-1979.

Figure 6.
U.S. Coal Supply Regions



SOURCE: Adapted by CBO from ICF, Incorporated.

Figure 7.
U.S. Coal Demand Regions



SOURCE: Adapted by CBO from ICF, Incorporated.

Though the nationwide demand for low-sulfur coal did rise during the 1970s, the characteristic of low-sulfur content does not appear to have caused that fuel's delivered price to be significantly higher than the delivered price for high-sulfur coals. Throughout the 1970s, the price of both high- and low-sulfur coal proceeded along roughly parallel upward paths (see Figure 8), with low-sulfur coal priced only slightly higher. The only anomaly in the pattern, also evident in the illustration of deliveries (Figure 5), occurred in 1978, coincident with a strike of mine workers against coal producers; though pronounced and causing a brief, inexplicable gain for high-sulfur coal over low-sulfur coal, this episode represents only a temporary disturbance on the otherwise quite regular course of both low- and high-sulfur coal prices. The fact of no significant difference between the delivered price of both coals suggests that buyers, at least in the 1970s, were willing to pay only a slight premium for low-sulfur content over the cost of locally available coals.

In conclusion, though increased demand for low-sulfur coal in the 1970s has occurred roughly simultaneous with implementation of utilities' plans to meet the 1971 NSPS, no firm correlation can be established, perhaps because the standards have not been in effect long enough. Nevertheless, the perceived potential for future distortions in the coal market prompted the Congress to take preventive measures in amending the Clean Air Act in 1977.

THE REVISED NSPS AND PROJECTIONS FOR U.S. COAL MARKETS

By requiring the installation of scrubbers in all new coal-burning generating plants, the revised NSPS of 1978 were designed to remove the attractiveness to utilities of using non-local low-sulfur coal. The requirement to remove a fixed percentage of sulfur dioxide when burning any type coal under the 1978 NSPS was designed to encourage the use of the cheapest coal available, usually a locally produced coal. In devising the new regulations, the EPA formulated projections through 1995 on the basis of a computer model simulation. 9/ The simulation indicated that, as a result of the proposed new standards, total pollutant emissions would be reduced through-

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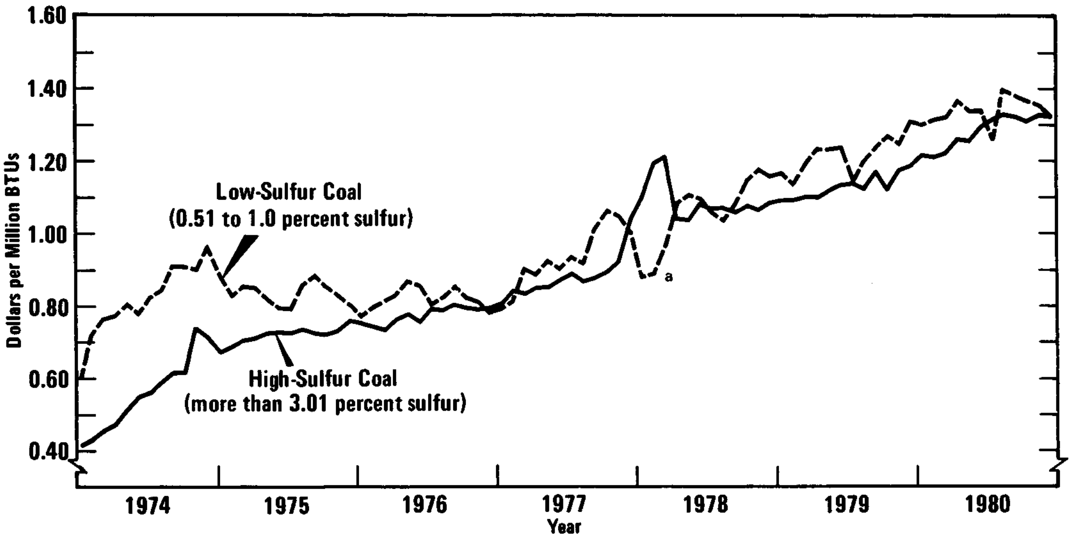
9. See ICF, Incorporated, "The Final Set of Analyses of Alternative New Source Performance Standards for New Coal-Fired Power Plants," prepared for the U.S. Environmental Protection Agency and Department of Energy (June 1979).

Figure 8.

U.S. Coal Prices, by Sulfur Content: 1974-1980



SOURCE: Adapted by CBO from data provided by Data Resources, Inc.

[a] Divergence coincident with mine workers' strike.

out the projection period, and that reliance on local coal would increase appreciably.

As part of a reexamination of the NSPS of 1978, the analysis in the remainder of this chapter attempts to assess what effects, if any, the revised NSPS will have on U.S. coal markets through the year 2000. Since the new standards were enacted, knowledge about scrubber costs, electricity growth, and coal supply has increased. To take account of this information in its analysis, the CBO requested ICF, Incorporated, a consulting firm specializing in coal-market information, to examine the effects of the 1978 NSPS on the basis of new assumptions developed by the CBO. ICF was chosen to conduct the modeling because it operates one of the most detailed coal and utility emissions models available, and because that model continues to be used by the EPA and other researchers to determine the effect of alternative standards on the utility and coal industries.

The purpose of the modeling was to establish a baseline of reasonable expectations for current policy with regard to three sets of issues: What quantity of air pollutant emissions can be expected from the utility sector through the year 2000? What are likely to be the annual and cumulative costs of the standards limiting these emissions? And what consumption and regional production levels of different coal types may be anticipated? (This same model is used in the analysis in Chapter VI that compares alternative emissions standards for sulfur dioxide--the most influential emissions limit--against this baseline and against each other.) The remainder of this chapter focuses on two aspects of the third issue: What type of coal is likely to be used within each consuming region, and where will that coal originate? The analysis is based on the assumption that the current NSPS will remain in force. (Appendix B details the assumptions and the methodology used.)

In the year 2000, the majority of projected new coal-fired capacity--that is, plants subject to the current NSPS--will be in the West South Central area and Atlantic seaboard states. Almost 100 gigawatts (60 percent) of the 168 gigawatts of new coal-fired electric capacity anticipated will be located in these areas (see Table 5). The area seen to experience one of the lowest growth rates in new coal-fired capacity is the southern Midwest (encompassing the East South Central area); the sizable commitment to new nuclear power in that region will tend to lower the Midwest's growth in coal-fired capacity, though recent nuclear plant cancellations may result in greater projected coal-fired capacity.

With regard to the sulfur content of coal burnt by new plants subject to the current NSPS, the pattern of overall consumption established late in the 1970s is expected to continue. Low-sulfur coal (generating less than 1.2 pounds of sulfur dioxide per million BTUs) is projected to meet roughly 60 percent of all new coal-fired utility demand by the year 2000. Much of that consumption is seen to occur in the Mountain and West South Central regions (36 percent), where low-sulfur coal naturally predominates; and the South Atlantic region (24 percent), where low-sulfur coal is available from Central Appalachia. Hence, the low-sulfur coal consumed in these regions will come largely from local supplies. In the East, North, and South Central areas of the Midwest, however, where low-sulfur coal is not mined, low-sulfur coal will supply approximately 60 percent of the regional demand in the year 2000 in power plants covered by the NSPS. Most of this supply will probably come from the West, indicating an accelerated trend toward western coal supplies. The growth in midwestern coal production (see Table 6), however, also indicates that many new power plants will choose to burn the locally produced high-sulfur coal under the NSPS.

Three western areas are projected to experience significant increases in total coal production. In the Rocky Mountain states, production is seen to rise by 578 percent; in the Southwest, it should rise by 468 percent; and in the Western Northern Great Plains, by 268 percent. These sizable growth rates are attributed partly to consumption by users in the West and West

TABLE 5. PROJECTED REGIONAL GROWTH IN COAL-FIRED ELECTRICITY, TO YEAR 2000

Region	Total 20-Year Growth in Coal-Fired Capacity (In gigawatts)	Total Projected Annual Coal Consumption (In millions of tons)	Percent Increase in Consumption from 1979
East (New England and Middle and South Atlantic)	44.2	290	110
East North Central	25.5	241	50
East South Central	3.6	88	23
West North Central	11.8	134	82
West South Central	54.2	275	535
West (Mountain and Pacific)	25.0	146	134
Total	164.3	1,174	114

SOURCE: CBO/ICF analysis.

South Central regions, and partly to increasing demand in the Midwest and East. In the year 2000, western coal will supply approximately 21 percent of all coal burnt by both new and old utilities east of the Mississippi. The majority of coal used in these areas, however, will still be supplied by midwestern and eastern (primarily Appalachian) producers.

These data indicate some important trends in coal markets. Most important, coal production is seen to rise in all U.S. regions, most notably in the western areas. The exception is Southern Appalachia; a slowing of production in Appalachia is to be expected, since these eastern reserves have been mined for longer periods and are declining in productivity.

Also important is the increasing amount of western coal shipped east by the year 2000. In 1979, eastward shipments of western coal are esti-

TABLE 6. REGIONAL COAL PRODUCTION FOR 1979 AND PROJECTED TO THE YEAR 2000 (In millions of tons per year)

Region	Base Year Production (1979)	Total Projected Annual Production	Percent Increase
Northern Appalachia	187	331	77
Central Appalachia	213	342	61
Southern Appalachia	24	21	-13
Midwest	131	252	92
Central West	14	17	21
Gulf	26	119	358
Eastern Northern Great Plains	14	44	214
Western Northern Great Plains	104	383	268
Rocky Mountains	27	183	578
Southwest	25	142	468
Northwest/Alaska	5	33	560
Total	770	1,867	142
Total Western Coal Shipped to Eastern Utilities	22a/	127	477

SOURCE: CBO/ICF analysis.

a/ Estimate obtained from data in U.S. Department of Energy, Bituminous and Subbituminous Coal and Lignite Distribution, Calendar Year 1979.

mated to have been some 23 million tons; by the year 2000, these are projected to be 127 million tons--an increase of more than 450 percent. (Most western coal shipped east comes from Powder River Basin in Montana and Wyoming and goes to Ohio, Indiana, and Illinois.) This increase can be compared to growth in overall coal production, which is estimated to rise by 142 percent over approximately the same period. Thus, even under the current NSPS, with their intent to promote reliance on local resources, western coal penetration of the midwestern and eastern markets is seen to increase substantially throughout the remainder of this century.

To a large extent, the increase of western coal sales in midwestern markets is projected because inexpensively mined--hence low-priced--western coal can be shipped long distances and still retain a competitive edge over local coal supplies. For example, it is estimated that in the year 2000, a Wyoming Powder River coal shipped 1,000 miles to Indiana at 20 mills per ton-mile--achieving a delivered cost of $1.64 per million BTUs--will still underprice a locally produced Indiana coal shipped 100 miles at a delivered cost of $1.68 per million BTUs. 10/ However, this slight competitive edge is highly sensitive to transportation rates, which, if they rise higher than projected, can result in much higher delivered prices for Western coals shipped long distances.

The different control requirements for high- and low-sulfur coal also are expected to have some influence, though a small one, on U.S. coal markets. The lower control requirement of 70 percent for low-sulfur coal (instead of 90 percent) was originally established in recognition of the higher marginal cost of reducing sulfur dioxide from coals already low in sulfur content. This lower control requirement, however, is expected to provide a small cost advantage to some users of non-local low-sulfur coal. For example, the total cost differential of scrubbing a high-sulfur midwestern coal versus that of scrubbing a low-sulfur western coal is roughly 4.5 mills per kilowatt-hour, or approximately $8.70 more per ton than using the low-sulfur western coal. (This estimate is based on a 500-megawatt power plant burning western coal with a heat content of 10,000 BTUs per pound.) This differential would favor the purchase of low-sulfur coal over an equivalent-cost high-sulfur coal within an approximate radius of 500 miles. Such differentials are not large enough, though, to cause large-scale distortions in the U.S. coal market.

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10. Because Wyoming Powder River coal and Indiana Interior Basin coal have different energy contents, their delivered price reflects the total cost of buying and shipping the equivalent amount of fuel energy, expressed as one million BTUs.

Mining costs and transportation rates remain the major determinants of coal selection under the current standards, while low sulfur content is only a small influence. In this respect, the current standards should eliminate only a portion of the perceived encouragement to use non-local coal supplies. In the next chapter, the effects of alternate standards are examined and compared to the current standards to determine what effect, if any, different sulfur dioxide emissions limits may have on total emissions, on the costs of compliance, and on the production and distribution of coal.

CHAPTER VI. CHOICES FOR NEW SOURCE PERFORMANCE STANDARDS

The Congress is now considering possible changes to the Clean Air Act, and the debate will almost certainly include a reexamination of the new source performance standards. This chapter outlines various possible courses of action with respect to the NSPS, altering only the way they restrict emissions of sulfur dioxide. The analysis focuses primarily on three aspects of the alternative approaches:

- Total projected emissions of sulfur dioxide under each option;
- The costs of each alternative to the electric utility industry and to consumers; and
- The production and distribution of U.S. coal.

ALTERNATIVE EMISSIONS STANDARDS

To provide a framework for Congressional consideration of the Clean Air Act, the CBO has projected the possible outcomes of four alternative standards for the NSPS that became effective in 1978. Being current law, though subject to change through EPA review at intervals of four years or less, the 1978 NSPS are treated as one basis against which the alternatives are measured; comparison of each alternative against the others is equally important, however, and is a critical part of the analysis. The four alternatives to current law that the CBO has analyzed include one option that would be a reversion to the NSPS of 1971, a second and third that would alter the imposition of percentage reductions for sulfur dioxide that are stipulated in current law, and a fourth that would allow a balance of sulfur dioxide emissions control between old and new sources to achieve the same level of control as would the current NSPS. Descriptive details of these four options are given on the following pages; the essential characteristics are summarized in Table 7. 1/

1. The model used to project the effects of the options is described in Appendix B.

TABLE 7. SUMMARY OF CURRENT AND ALTERNATIVE EMISSIONS STANDARDS

Current Law and Options	Mass Emissions Limits (In pounds of sulfur dioxide per million BTUs of fuel consumed)
Current Law—New Source Performance Standard of 1978 a/	1.2 pound ceiling 0.6 pound floor
Option I—Revert to 1971 New Source Performance Standard a/	1.2 pounds
Option II—Achieve 70 Percent Emissions Control and Set an 0.8 Pound Floor for Sulfur Dioxide Emissions a/	1.2 pound ceiling 0.8 pound floor
Option III—Achieve 90 Percent Emissions Control and Set a 0.6 Pound Floor for Sulfur Dioxide Emissions a/	1.2 pound ceiling 0.6 pound floor
Option IV—Constrain Total Emissions Growth by Balancing Sulfur Dioxide Emissions Control Between Old and New Sources	New plant must meet current NSPS emissions level if no tradeoff used; if emissions are reduced at an existing plant new plant may increase its emissions beyond current NSPS level by same amount

a/ Applies to new or modified sources only.

Option I. Revert to the New Source Performance Standards of 1971

Reenactment of the 1971 NSPS, as described in Chapter II, would require coal-fired utility plants to limit emissions of sulfur dioxide gas to 1.2 pounds for every one million BTUs of fuel burnt. (For brevity, the

TABLE 7. (Continued)

Required Percentage Reduction Level	Comments
90 percent for emissions between floor and ceiling; 70 percent or more if emissions are below floor	Requires all coal to be scrubbed regardless of sulfur content
None	Allows low-sulfur eastern and western coal to be used without scrubbing
70 percent for emissions between floor and ceiling; none required if emissions are below floor	Allows much western and some eastern coals very low in sulfur content to be used without scrubbing
90 percent for emissions between floor and ceiling; none required if emissions are below floor	Eliminates scrubbing for some low-sulfur western coals; reduces scrubbing for most western and some eastern coals
Same as current law if no emissions trading used; none or variable when trading used, depending on reduction needed to meet constraints	Limits projected emissions to those calculated under current law; allows new and old facilities within a state to decide individual control levels so long as the limit on total emissions is not violated

SOURCE: Congressional Budget Office

following text expresses such a standard as 1.2 pounds SO_2 per million BTUs.) An electric utility subject to this standard could comply either by using low-sulfur coal without sulfur dioxide emissions controls (a scrubber), or by using a scrubber and burning a cheaper higher-sulfur coal. The primary distinctions of this standard over its successor are that it leaves scrubbers optional and that it does not require a set percentage reduction of potential sulfur dioxide emissions.

Option II. Achieve 70 Percent Emissions Control and Set a 0.8 Pound Floor for Sulfur Dioxide Emissions

This alternative would scale down the current standards' requirement that utilities control sulfur dioxide emissions by 90 percent when burning high-sulfur coal; it would also eliminate the current requirement to use scrubbers in plants burning very low-sulfur coal. It would call for scrubbing (or another technique that can desulfurize flue gases) only if emissions were above a maximum control level, or "floor", set at 0.8 pounds SO_2 per million BTUs. No control requirement would be specified for emissions below this floor. Above the floor, sulfur dioxide emissions would have to be reduced by at least 70 percent, and in no case could emissions exceed the 1971 NSPS ceiling of 1.2 pounds SO_2 per million BTUs. Under this option, much western coal and some eastern (notably Appalachian) coal could be burnt without scrubbers.

Option III. Achieve 90 Percent Emissions Control and Set a 0.6 Pound Floor for Sulfur Dioxide Emissions

Though retaining the current NSPS requirement of 90 percent sulfur dioxide emissions control for utilities using high-sulfur coal, this option would lower the current control requirement for some low-sulfur coals and eliminate it entirely for others. The alternative would stipulate that sulfur dioxide emissions be reduced by at least 90 percent if they are between 0.6 and 1.2 pounds per million BTUs of fuel consumed, a requirement similar to the current standard. Unlike the current standards, however, no control requirements would be specified for emissions below 0.6 pounds SO_2 per million BTUs. Under this alternative, only some western coals could be burnt without scrubbers, although the control requirement for the remaining low-sulfur western and eastern coals would be significantly relaxed.

Option IV. Constrain Total Emissions Growth by Balancing Sulfur Dioxide Emissions Between Old and New Sources

Two features are unique to this option: first, it would operate on a state-by-state basis within a general, nationwide framework; and second, it could affect old sources as well as new ones. Total future sulfur dioxide emissions within each state would be limited to levels projected under the current NSPS, allowing operators of new and old utility plants within each state to meet the overall emissions limit by using any combination of measures. Thus, the alternative would allow new plants to increase their emissions above NSPS permitted levels, so long as commensurate emissions reductions occurred at existing sources within the same state. This is commonly termed "emissions trading," or "new source bubbling." 2/ For purposes of the CBO analysis, because western states contain few old coal-fired facilities, emissions trading was treated as permissible only in the 31 states east of the Mississippi River. All other new power plants were assumed to be required to meet current state or federal NSPS requirements, whichever was lower. (Limiting the analysis to the 31-state region reduced computation time and costs but not accuracy.)

Under such a plan, a utility planning a new plant would first determine the quantity of new emissions the contemplated plant would contribute to the area's atmosphere after complying with the current NSPS; this would establish a baseline for trading. That plant could then increase its sulfur dioxide emissions by a measured amount above the baseline, so long as emissions from one or more already existing sources were reduced by an equal amount. In this procedure, overall incremental emissions would be held to current NSPS levels, but the burden of control could be distributed between utilities operating new and old sources. For purposes of analysis, emissions trading was treated as being limited to intrastate areas, assuming that such a plan would not allow negotiation over state boundaries; this assumption tended to produce results showing higher costs than plans allowing emissions trading between states. 3/ It was also assumed that this option would allow new sources to trade emissions allowances with an existing source only so long as the latter continued to operate. 4/

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2. "Bubbling" is a calculating procedure that envisions each state as having an enclosing overhead bubble within which the utility emissions of that state are contained; additions and subtractions of pollutant emissions are treated as occuring within the confines of that bubble.

3. Administration of this option would probably be complex and perhaps somewhat costly in terms of both money and time. Because the administrative mechanics of implementing this plan are purely conjectural, this analysis disregards any potential such costs the option might entail.

4. Should the existing facility be retired, the new source would have either to apply the tradeoff to another existing facility in the region or reduce its own emissions by the amount originally slated for trading.

COMPARISON OF ALTERNATIVE EMISSIONS STANDARDS

For a continuation of current law and each of the alternative emissions standards outlined, the CBO projected sulfur dioxide emissions, costs, and coal use.

Effects on Emissions and Control Costs

The highest growth in sulfur dioxide emissions from new coal-fired power plants would be allowed under Option I, increasing total utility emissions from an annual 17.6 million tons in 1979 to 22.8 million in the year 2000. 5/ Both the current standards and Option IV would limit total emissions to 21 million tons by the year 2000, the lowest increase of all the alternatives. Total emissions under the other choices--Options II and III--would tend to fall between these upper and lower bounds. Table 8 shows total projected emissions of all the alternatives examined, including the current standards. 6/

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5. As stated in Chapter II, these increased emissions would accompany the addition of 168 gigawatts of new coal-fired electrical capacity anticipated.

6. Four cautions must be noted, however, when comparing the costs and projected emissions. First, the current NSPS and Option IV could yield the lowest level of future sulfur dioxide emissions. This does not give a measure of the health effects or costs of allowing pollutant levels to rise beyond the current standards; whether any analyis could assess these effects from such small differences in projected emissions is doubtful. Second, if new sources using emissions tradeoffs from existing plants were allowed to retain the higher emissions limits after the existing plants were retired, the bubbling approach could leave a dirtier generation of new plants than would be allowed under the current NSPS; however, this analysis assumes that regulations under Option IV would not permit this. Third, the long operating life of most electric plants--usually about 50 years--suggests that most existing sources that could be useful for emissions offsets (as under Option IV) would continue to operate through the year 2010, after which a sharp drop in utility emissions could be expected because of the surviving generation of cleaner plants. Since the surviving plants would be required to lower emissions to reach the original standards, then the predicted cost effectiveness over the life of the plants could drop (that

Power plants subject to neither of the Clean Air Act's NSPS can emit twice to six times the volume of sulfur dioxide than do plants that are regulated under the standards. Therefore, emissions from facilities not subject to either standard dominate the projections shown in Table 8. New plants under the most stringent national standards--the current NSPS--will contribute only 1.6 million of a total projected 21 million tons of sulfur dioxide emissions in the year 2000. Similarly, even under the most lenient standards--Option I--new plants will contribute only 4 million of a total 22.8 million tons of sulfur dioxide in the year 2000. The difference between the emissions projected for new units under current law and Option I is only 2.4 million tons. In both cases, roughly eight-tenths of all sulfur dioxide emissions would arise from units in existence during the early 1970s--that is, those facilities subject to neither NSPS. This disparity is attributable primarily to the higher emissions rates associated with older sources. For example, the average emissions rate in the year 2000 from a power plant that is subject to neither of the act's emissions standards is estimated to be 2.6 pounds SO_2 per million BTUs, compared to an average emissions rate of 0.4 pounds SO_2 per million BTUs for plants operating under the stringent 1978 NSPS.

Judgments about cost effectiveness can be made from comparing the costs incurred by reducing sulfur dioxide emissions from the highest projected levels--in this case, 22.8 million tons by the year 2000 under Option I. Under the current NSPS, sulfur dioxide removal is projected to cost $2,411 a ton. Removal costs under Option II would be $1,929 a ton. Option III--by far the most expensive choice according to this measure--would incur a removal cost of $3,400 a ton. Option IV, in sharp contrast, would permit sulfur dioxide removal at only $550 a ton at the end of the projection period.

Option IV would offer the utilities the greatest economic efficiency, because it would permit fuel-switching as a substitute for scrubbers;

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6. (continued)
is, become more expensive per ton of sulfur dioxide removed), depending on the cost of the new control technique chosen. Finally, the mandatory installation of scrubbers under the current NSPS provides a form of insurance against increased levels of sulfur dioxide emissions that could result from the burning of high-sulfur coal, under possible emergency situations. For these reasons, only partial conclusions about the full benefits of each alternative relative to cost can be drawn in this study.

TABLE 8. TOTAL PROJECTED SULFUR DIOXIDE EMISSIONS AND COMPARISON OF COST EFFECTIVENESS UNDER CURRENT LAW AND ALTERNATIVE STANDARDS

Emissions Under Current Law and Alternative Standards	Total Nationwide Sulfur Dioxide Emissions (In millions of tons per year)			Incremental Cost of Sulfur Dioxide Reductions Below 1971 NSPS (In 1980 dollars per ton reduction)	
	1979	1990	2000	1990	2000
Current Law					
Total	17.6	20.7	21.0	1,800	2,411
New Sources	None	0.4	1.6		
Option I a/					
Total	17.6	21.1	22.8	N/A b/	N/A b/
New Sources	None	0.8	4.0		
Option II					
Total	17.6	21.0	22.1	None	1,929
New Sources	None	0.6	2.8		
Option III					
Total	17.6	21.1	21.9	None c/	3,400
New Sources	None	0.4	2.0		
Option IV					
Total	17.6	20.7	21.0	900	550
New Sources	None	0.4	2.5		

SOURCE: CBO/ICF analysis.

a. Incremental cost of sulfur dioxide emissions reduction represents cost of control beyond these standards.

b. Not applicable.

c. No significant emissions reduction is achieved beyond Option I, although annual costs are increased by $360 million.

switching to a lower-sulfur coal at existing power plants to reduce the control requirements for new plants would lower annual costs while achieving the same emissions reductions as the current NSPS. For example, switching an existing 500-megawatt plant from a high-sulfur coal at 3.33 pounds SO_2 per million BTUs to a medium-sulfur coal at 1.66 pounds SO_2 per million BTUs could reduce emissions at a rate of $431 per ton removed. By contrast, a new plant of comparable size but equipped with a scrubber may incur costs of $1,230 for each ton of sulfur dioxide removed beyond the level that would be required under Option I.

Measures of cost effectiveness can only be taken as rough gauges of economic efficiency, however. For example, although the current NSPS cost less per ton of sulfur dioxide removed than would Option III, they are actually more expensive in terms of capital and annual charges (the next section examines these costs). They remove more sulfur dioxide, however, and hence are less costly per ton removed. Thus, consideration of these options should include total costs as well as costs per ton.

Cost Effects on the Utility Industry

Annual costs of air pollution regulations to the utility industry are a function of two factors: the capital and operating costs of pollution control equipment and the increased premiums associated with purchasing and shipping low-sulfur coal.

Capital Costs. In general, the capital requirements of each alternative are roughly proportional to the amount of scrubber control needed. The current NSPS are projected to involve the greatest capital outlay, approximately $33 billion between 1980 and 2000 (see Table 9); that large capital expense is attributable for the most part to the need to install scrubbers to meet the standards.

At the other end of the spectrum, capital outlays for the moderate amount of optional scrubbing entailed in meeting the NSPS of 1971 (Option I) are projected to total only $14 billion over the 1980-2000 period.

The two choices that stipulate emissions floors (Options II and III) would reduce the overall costs of scrubbing by eliminating mandatory desulfurization for very low-sulfur coals and by allowing many coals to meet the emissions floor with only moderate reduction levels (70 percent and less). High-sulfur coals in both of these options would still need to be scrubbed by either 70 percent (Option II) or 90 percent (Option III), affecting primarily the midwestern and Atlantic seaboard states; in both cases, the

TABLE 9. PROJECTED COST EFFECTS ON THE UTILITY INDUSTRY OF ALTERNATIVE EMISSIONS STANDARDS

	Current Standards	Option I	Option II	Option III	Option IV
Cumulative Capital Requirements (In billions of 1980 dollars)					
1990	8.30	3.90	4.50	4.10	6.60
2000	33.40	14.00	14.60	17.10	14.70
Projected National Scrubber-Equipped Capacity (In gigawatts)					
1980	45.70	45.70	45.70	45.70	45.70
1990	81.60	55.80	59.00	55.30	73.00
2000	213.50	73.30	77.40	87.30	123.40
Approximate Annual Costs (In billions of 1980 dollars)					
1980	5.35	5.35	5.35	5.35	5.35
1990	8.10	7.38	7.38	7.74	7.74
2000	14.10	9.76	11.11	12.82	10.75
Nationwide Average Generating Costs of Air Pollution Control (In 1980 mills per kilowatt-hours)					
1980	2.34	2.34	2.34	2.34	2.34
1990	2.57	2.34	2.34	2.46	2.46
2000	3.43	2.37	2.70	3.12	2.62

SOURCE: CBO/ICF analysis.

use of an emissions floor requiring no further control would tend to reduce significantly the amount of scrubbing needed in the western states. The capital costs for Option II and III are estimated to total between $14 and $17 billion for the 1980-2000 period.

Option IV would require scrubbing only in instances in which a new source could not find an old one to serve as a trading partner with which to balance emissions allowances. Because of the high degree of emissions control mandated in this latter option, more scrubbing is envisioned than for Option I (at roughly the same capital expense) although much less than for the current standards.

Generating Costs. The current NSPS would result in the highest expected annual cost ($14 billion in the year 2000), while Option I would result in the lowest ($10 billion). Option IV would entail lower annual costs after 1990 ($11 billion per year by the year 2000) once significant coal-fired capacity growth had begun in the East, where the most existing capacity is available for cost-effective emissions trading purposes (see Table 9).

The current NSPS would have the highest generating cost associated with pollution control primarily because of the current fixed and variable charges of using scrubbers. The 3.43 mills per kilowatt-hour charge in 2000 (shown in Table 9) under the current standards would translate into approximately $1.72 for a monthly electricity use of 500 kilowatt-hours. This represents approximately 6 percent of the average residential electricity charge recorded in 1980. 7/

Option I would exact the lowest average generating costs for emissions control--2.37 mills per kilowatt-hour. This cost is not projected to change appreciably through the year 2000, largely because the proportion of present scrubber-equipped capacity compared to total capacity would not change significantly. In addition, though the standards under Option I would encourage use of low-sulfur coal, and thus could slightly raise annual operating costs, that increase would be insignificant when averaged over total electricity production. Overall, the utilities' operating costs for air pollution control would rise by less than 5 percent.

The two alternatives that set emissions floors, Options II and III, would involve average generating costs higher than under Option I but lower than under the current standards. This cost would occur because both scrubber and low-sulfur coal use under both options would fall somewhere between that under Option I and the current standards. The price of and demand for low-sulfur coal would be lower than under Option I but higher than under

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7. See U.S. Department of Energy, 1980 Annual Report to Congress (April 1981).

current NSPS; conversely, the scrubbing costs of both Options II and III would be lower than under the current NSPS but higher than under Option I.

Aside from Option I, Option IV would result in the lowest generating cost for pollution control--2.62 mills per kilowatt-hour in 2000. At the same time, Option IV would also achieve the lowest projected emissions levels. The combination of low cost and high emissions control would occur because many old sources would switch to low- or medium-sulfur coal as an economical method for curbing emissions and reducing the burden of emissions control at newer sources (through emissions trading). When the older units used for emissions trading retired, however, the annual generating costs of Option IV might rise. Assuming normal plant retirement rates, however, this rise would not likely occur until after the year 2010.

Other Cost Factors. The sensitivity of electricity costs to other factors besides pollution control--notably fuel transport--is important. To test this sensitivity, the CBO also examined the influence of continued real increases in rail rates (in addition to the generic assumptions outlined in Appendix B). In assessing Option I, the CBO assumed high rail rates; the results showed that if rail rates rose an additional 15 to 25 percent in real terms during the 1985-1990 period, the incremental (that is, real) cost to electricity users in the year 2000 would be 5.34 mills per kilowatt-hour--up 128 percent over the present rate of 2.34 mills per kilowatt-hour and higher than the rate resulting from either the current standards or from any other option. Interestingly, the higher transportation costs could stimulate an increase in the numbers of scrubbers built for new plants under Option I, since high-sulfur coal use with scrubbing would become more economical in many cases than shipping low-sulfur western coal to the Midwest.

Coal Consumption and Production

Because of the long lead time that precedes a new coal-fired power plant's becoming operational, effects associated with any emissions control strategy initiated today would not be observable until the mid- to late-1990s. Accordingly, coal-market effects in the year 2000 would best indicate the influence of standards enacted now as alternatives to the current law 1978 NSPS.

Coal Consumption. Coal consumption by electric utilities generally determines the production patterns of all U.S. coals. Under each of the options analyzed here, as well as under current law, total coal consumption by the utilities is seen to be divided roughly between the western and eastern halves of the country in the year 2000. The West South Central